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Final Deliverable – 5

Economic Modeling & Optimization

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How to Read this Document

The audience for this report includes utilities and anyone looking to optimally apply the System Levelized Cost of Energy (System LCOE) methodology to Serve Load. Considering the metrics set forth in Final Deliverable - 1 (FD-1), the Austin SHINES project deployed a fleet of Distributed Energy Resources (DERs). These metrics guided the establishment of a System Levelized Cost of Electricity (System LCOE) methodology; wherein FD-1 stated the load served would enable 25% photovoltaic (PV) penetration (by energy) at a System LCOE cost of <= $0.14/kWh, while maintaining system reliability and power quality. A fleet of DERs can assume different mixtures, each of which serves the load at a different LCOE. The optimal mixture of DERs will serve load at the smallest System LCOE.

The search for the optimal mixture is an iterative process and involves studying numerous DER deployment scenarios, identifying the significant variables, the sensitivity of System LCOE with respect to these variables, and altering the combination of DERs in the model. This report documents the iterative modeling process of determining the optimal design of Austin SHINES. Based on the key assumptions and economic data described in FD-1, the design is 'locally' optimal meaning that in case of Austin SHINES, this mixture of DERs has the smallest System LCOE -among all the examined scenarios, at a certain solar penetration. The optimal mixture can change, if the conditions of the system including the economic data, regulation, or policies of the energy market change.

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Section 1 **Applied System LCOE Methodology**

1.1 Final Deliverable - 1 Outcomes

In Final Deliverable 1 (FD-1), a methodology for System LCOE calculations was proposed. Figure 1-1 shows the core equational definition of System LCOE. Section 1.1.1 summarizes the baseline System LCOE results, while Section 1.1.2 reviews the System LCOE analysis of Scenario 3. This analysis aims to set the stage for the economic optimization presented in Section 2.

$$\text{System LCOE to Serve Load}\left(\frac{\$}{kWh}\right) =$$

$$\frac{\begin{bmatrix}\text{Capital cost of}\\ \text{all equipment}\\ \text{within system (\$)}\end{bmatrix} + \begin{bmatrix}\text{Operating cost of}\\ \text{all equipment}\\ \text{within system (\$)}\end{bmatrix} + \begin{bmatrix}\text{Net value of}\\ \text{energy, capacity and services}\\ \text{that cross system boundary (\$)}\end{bmatrix}}{\begin{bmatrix}\text{All load served}\\ \text{within system (kWh)}\end{bmatrix}}$$

Figure 1-1 System LCOE definition

1.1.1 Baseline System LCOE Result

The top-level System LCOE results for the baseline circuits are summarized in Table 1-1 for the Kingsbery (KB) system and the Mueller (MU) system. The baseline System LCOE is $0.088/kWh for the KB circuits and $0.090/kWh for the MU circuits over the course of the calendar year in the mod-DER and mod-ERCOT cost assumption set, which takes mid-range estimates for all DER costs and all wholesale market prices. This calculation uses the costs of the utility-owned infrastructure as it exists today, the cost of the DERs that exist in the system today, and the cost of the purchase of energy from ERCOT wholesale markets over the course of the calendar year. All costs are on an annualized basis. The capital and operating costs are derived from the rate case, which produces a yearly cost. The net cost of energy and services imported to the system is integrated over the test year, as is the load served and solar penetration.

Table 1-1: Baseline System LCOE

Scenario description		KB Baseline	MU Baseline
System LCOE to serve load ($/kWh)	lo-DER lo-ERCOT	$0.082	$0.084
	lo-DER hi-ERCOT	$0.093	$0.096
	mod-DER mod-ERCOT	$0.088	$0.090
	hi-DER lo-ERCOT	$0.082	$0.084
	hi-DER hi-ERCOT	$0.093	$0.096
Annualized capital cost of infrastructure to serve load ($)	lo	$3,046,807	$1,868,189
	mod	$3,046,807	$1,868,189
	hi	$3,046,807	$1,868,189
Annual operating cost of infrastructure to serve load ($)	lo	$90,269	$75,172
	mod	$90,269	$75,172
	hi	$90,269	$75,172
Net annual cost of energy and services imported to system ($)	lo	$2,284,101	$1,309,665
	mod	$2,672,511	$1,526,426
	hi	$3,060,921	$1,743,188
Sum of load served within system over test year (kWh)		6.64E+07	3.85E+07
Solar PV penetration by energy over test year (%)		1.0%	5.3%

The System LCOE to serve load is similar between the two circuits, at $0.088/kWh in KB and $0.090/kWh in MU. Because almost all the energy consumed is purchased from the ERCOT wholesale energy market in the base case, rather than generated locally, the System LCOE is sensitive to ERCOT costs, but not very sensitive to DER costs. The computed value of each term is listed in Table 1-1 for the md-DER md-ERCOT cost.

1.1.2 System LCOE Methodology: Example

This section demonstrates the application of the System LCOE methodology developed in the FD-1 document. The methodology was applied to MU circuit with 25% solar penetration and two 0.99MW/2MWh utility-scale ESS. Table 1-2 shows details of this scenario.

Table 1-2: Scenario 3

Scenario No	PV (MW)		ESS (MWh)			EV (MWh)	Load Control
	Distributed	Community	Utility	Residential	Commercial		
3	4.9	0	4	0	0	0	No

Figure 1-2 shows the results of System LCOE calculations for this scenario. The $\Delta SystemLCOE_{SHINES}$ is 14% lower than the $\Delta SystemLCOE_{Base}$ which does not meet the requirement of the second SHINES metric (%delta metric).

Please Note the System LCOE ($/kWh) is represented by 3 decimal figures. These are rounded for display purposes, and any discrepancies to the %delta metric can be proven through the accompanying spreadsheet *FD5_System LCOE Calculations.exe*. The %delta metric is therefore the true value in these graphs. The same holds for all 14 scenarios represented in the results of Section 2.3. Thus the %delta metric cannot be determined “by hand” from the signficant figures provided, and should be considered a close representation for illustrative comparison. This will be restated again, later in the document.

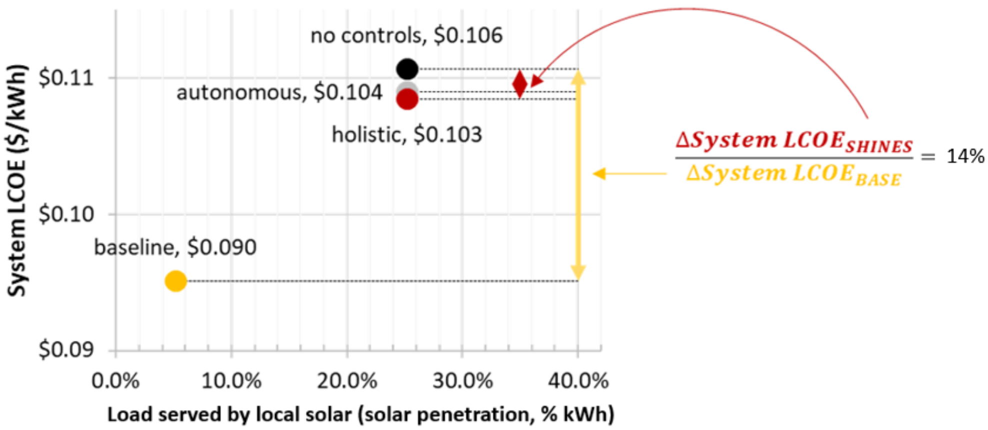


Figure 1-2 Example set of System LCOE results; Scenario 3

Figure 1-3 is a two-part figure that shows the same results as shown in Figure 1-2, in different format. Figure 1-2 explicitly labels the $\Delta SystemLCOE_{SHINES}$ and $\Delta SystemLCOE_{Base}$; In Figure 1-3 they are called out by the same red and yellow arrows but not explicitly labeled for a more compact presentation. The right panel of Figure 1-3 shows the contributions to System LCOE from categories of costs.

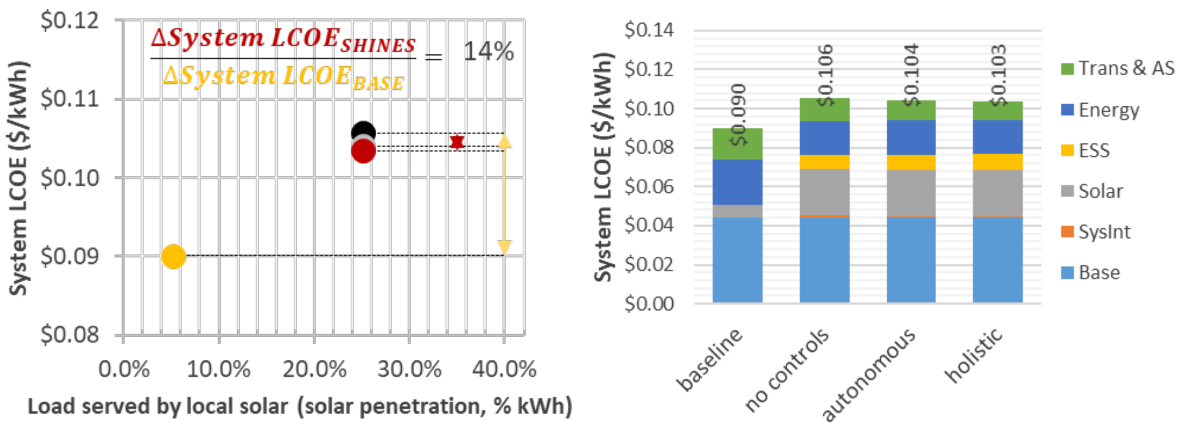


Figure 1-3 Scenario 3, Left: System LCOE results for each control strategy, Right: System LCOE breakdown

The baseline system costs in light blue are the wires, poles, transformers, substation equipment, etc., the conventional system equipment that is already present on the feeder and constant across the four scenarios. The System Integration costs in orange represent the cost of any conventional upgrades that would be required to absorb the distributed solar. A deployment of the VVO system was identified as the best approach for mitigating overvoltage. It also represents the replacement cost of secondary service transformers with a higher-rated model that experienced overloading during peak solar production. Holistic controls adjust the operation of the distributed solar and ESS so that firm capacity upgrades are not required, so this cost decreases between the no controls case and the holistic controls case. In gray is the cost of the solar PV, and the yellow is the cost of the ESS. This includes both hardware cost and the additional incremental cost of communication and controls for the cases with more sophisticated controls. The net wholesale energy costs, in dark blue, decrease significantly between the base case and the high-solar cases, since more of the energy that is needed is produced locally and less imported energy is required. There is a small decrease between the no controls case and the holistic controls case due to the opportunistic discharging of the ESS under the RTPD application. The transmission and AS cost, in green, have the most significant decrease between the no controls case and the holistic controls case, since PLR is the most valuable application. Strictly speaking, the utility-scale ESS deployment is assumed to be in the form of two assets, each limited to 0.99MW so that it can participate in

PLR and reduce the transmission system costs. Breaking the utility-scale ESS up into systems that are each barely under 1MW ensures that all can participate in PLR, which is the most valuable of the wholesale market applications by a significant factor. One ESS is connected mid-feeder where the fielded MU 1.5MW ESS is deployed, and one ESS is connected at the substation bus, similarly to the fielded KB ESS. More detailed information about the implementation of the controls in each case can be found in Table 1-3.

Table 1-3: Scenario 3; System LCOE results summary

Scenario	Baseline	No Controls	Autonomous	Holistic
Solar PV penetration by energy (%)	5%	25%	25%	25%
System LCOE to Serve Load ($/kWh)				
low DER costs, low ERCOT prices	$0.084	$0.096	$0.095	$0.094
low DER costs, high ERCOT prices	$0.096	$0.105	$0.103	$0.103
mod. DER costs, mod. ERCOT prices (charted in Figure 1-3 left)	$0.090	$0.106	$0.104	$0.103
high DER costs, low ERCOT prices	$0.084	$0.111	$0.109	$0.109
high DER costs, high ERCOT prices	$0.096	$0.120	$0.118	$0.118
System LCOE to Serve Load by Category (mod. case charted in Figure 1-3, right)				
Base distribution system infrastructure	$0.044	$0.044	$0.044	$0.044
System integration	$-	$0.001	$0.000	$0.000
Solar CapEx and OpEx	$0.006	$0.024	$0.024	$0.024
ESS CapEx and OpEx	$-	$0.007	$0.008	$0.008
EV CapEx and OpEx	$-	$-	$-	$-
Net wholesale energy	$0.023	$0.017	$0.018	$0.018
Transmission and ancillary services	$0.016	$0.012	$0.010	$0.009

The top-level results for the scenario set summarized in Figure 1-2 are summarized in Table 1-3. All costs are on an annualized basis. The net cost of energy and services imported to the system is integrated over the test year, as is the load served and solar penetration. The wholesale market costs, the sum of all energy, transmission, and ancillary service costs, are reduced by 8% by the actions of the ESS in the holistic controls case, as compared to the no controls case. The approach taken in the analysis of Section 3 will be used in the economic optimization of Austin SHINES presented in the next section.

Section 2 **Economic Optimization**

This Section presents the process of determining the ultimate design mix for the Austin SHINES project. The analysis is mostly focused on MU circuit. Since KB has similar economics as MU and does not demonstrate reliability issues at 25% solar penetration, the process of determining the ultimate design mix for KB will be similar to MU. Note that in case reliability related issues arise in the system, the economics of these two circuits will be different from each other and the optimization must be carried out separately for each circuit.

The goal of the analyses in this section is to answer the following questions

- What is the amount of energy storage required to optimally capture the value of solar?
- What is the optimal energy storage deployment Scenario (i.e. utility-scale vs. community vs. residential)?
- What is the optimal solar deployment Scenario (i.e. community vs. residential)?
- What is the optimal control strategy?

The ultimate design will be determined in an iterative process. In every iteration, a different mixture of assets is examined, then depending on the System LCOE results, the mixture of assets will be changed, and the process continues until the mixture with smallest System LCOE is determined. The process starts with single technology scenarios in which only one type of ESS technology will be deployed (i.e., utility-scale, residential or commercial). In the next step, the single technology scenarios with more storage will be examined to determine the impact of increasing the of storage on System LCOE. The third step of economic optimization considers several multi-technology scenarios where there is more than one type of storage technology in the circuit. The multi-technology scenarios can help study the interactions of multiple technologies.

2.1 Key Assumptions

In addition to the assumptions listed in FD-1, the economic optimization described in this Section, assumes the following:

- Optimization focuses on MU only as the circuit is smaller and thus the runtime of simulation scenarios is shorter. KB has similar economics.
- Optimization only considers 2-hour battery ESS regardless of the asset type. This will decrease the number of variables to consider when optimizing the mixture of assets.

2.2 Definition of Scenarios

Table 2-1 shows the list of all the simulations scenarios included in the economic optimization along with their asset mixtures. Note that each scenario consists of three sub-scenarios with different control strategies, i.e. no controls, autonomous controls, and holistic controls. More details on the definition and implementation of control strategies for each type of assets can be found in FD-1.

The following Section will summarize the key findings from simulation scenarios listed Table 2-1. For the sake of brevity, only a selection of these scenarios will be discussed in detail. Additional details of System LCOE calculations for all these scenarios are included in Attachment A.

Table 2-1: List of simulation scenarios and their asset mixes

Scenario	Solar penetration by energy (%)	Distributed solar (MW)	Community solar (MW)	Utility ESS (MWh)	Residential ESS (MWh)	Commercial ESS (MWh)	EV (MWh)	Load Control
1	25	4.9	0	1	0	0	0	No
2	25	4.9	0	2	0	0	0	No
3	25	4.9	0	4	0	0	0	No
4	25	4.9	0	6	0	0	0	No
5	25	4.9	0	0	1	0	0	No
6	25	4.9	0	0	2	0	0	No
7	25	4.9	0	0	0	1	0	No
8	25	4.9	0	0	0	2	0	No
9	25	4.9	0	2	1	1	0	No
10	25	4.9	0	1	2	1	0	No
11	25	4.9	0	1	1	2	0	No
12	25	1.8	3.1	2	0	0	0	No
13	25	4.9	0	0	0	0	2	No
14	25	4.9	0	2	0	0	0	Yes

2.3 Results

This Section discusses the results of an economic optimization which determines the ultimate design mix of Austin SHINES. This economic optimization takes an iterative approach in which each iteration assesses deployment of various sets of technologies in the MU circuit. The optimization starts with single-technology scenarios, gradually increases the volume of storage and then moves to scenarios which deploy multiple technologies at once. At the end, the deployment of other assets such as EVs and demand-side (defined as "load control" in Table 2-1) management is examined.

Please Note the System LCOE ($/kWh) is represented by 3 decimal figures, for all 14 scenarios in Section 2.3. These are rounded for display purposes, and any discrepancies to the final %delta metric can be proven through the accompanying spreadsheet *FD5_System LCOE Calucations.exe*. The %delta metric is therefore the true value in these graphs, and cannot be determined "by hand" from the signficant figures provided. It should be considered a close representation for illustrative comparison.

2.3.1 Scenario 1

As shown in Table 2-1, Scenario 1 consists of 4.9 MW of distributed solar and a 0.5MW/1MWh utility-scale ESS. The ESS is assumed to be located at the node where the fielded MU ESS is installed. Figure 2-1 and Table 2-2 show a summary of the results for Scenario 1.

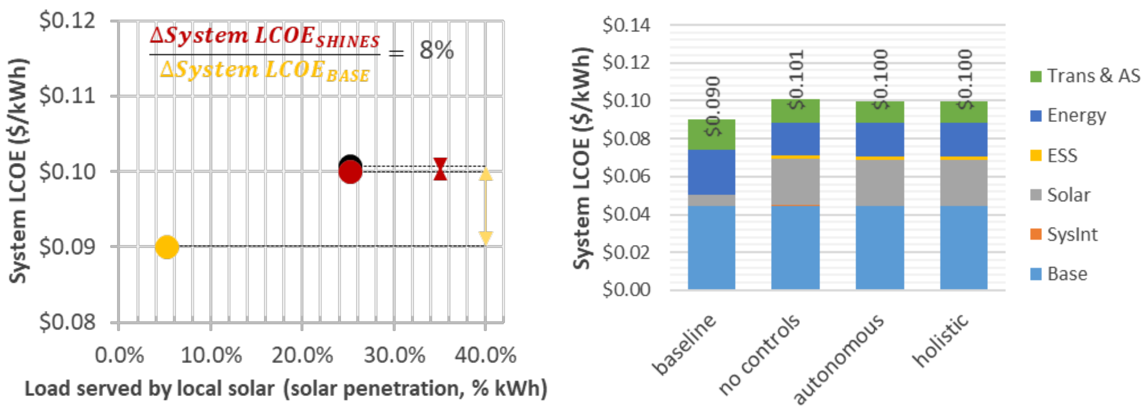


Figure 2-1 Scenario 1, Left: System LCOE results for each control strategy, Right: System LCOE breakdown

Table 2-2: Scenario 1; System LCOE results summary

Scenario	Baseline	No Controls	Autonomous	Holistic
Solar PV penetration by energy (%)	5%	25%	25%	25%
System LCOE to Serve Load ($/kWh)				
low DER costs, low ERCOT prices	$0.084	$0.092	$0.091	$0.091
low DER costs, high ERCOT prices	$0.096	$ 0.101	$0.100	$0.100
mod. DER costs, mod. ERCOT prices (charted in Figure 2-1, left)	$0.090	$0.101	$ 0.100	$ 0.100
high DER costs, low ERCOT prices	$0.084	$ 0.102	$ 0.101	$ 0.101
high DER costs, high ERCOT prices	$0.096	$ 0.111	$ 0.110	$ 0.110
System LCOE to Serve Load by Category (mod. case charted in Figure 2-1, right)				
Base distribution system infrastructure	$0.044	$ 0.044	$ 0.044	$ 0.044
System integration	$-	$ 0.001	$ 0.000	$ 0.000
Solar CapEx and OpEx	$0.006	$ 0.024	$ 0.024	$ 0.024
ESS CapEx and OpEx	$-	$ 0.002	$ 0.002	$ 0.002
Net wholesale energy	$0.023	$0.018	$0.018	$0.018
Transmission and ancillary services	$0.016	$0.012	$0.012	$0.012

The System LCOE of the cases with no controls, autonomous controls and holistic controls are, $0.101, $0.100, and $0.100 respectively which are very close to each other. The holistic controls sub-scenario has the smallest System LCOE among the three strategies. The %delta metric is 8% which indicates that holistic control captured more value compared to no controls, though the differential value is insignificant. The %delta metric is smaller than 20% and does not meet the second SHINES criterion.

2.3.2 Scenario 2

Similar to Scenario 1, Scenario 2 includes a utility-scale ESS connected to the same node as the fielded MU ESS. The ESS capacity in this scenario is 0.99MW/2MWh, which is slightly less than ERCOT's limit on unregistered distributed generation capacity (1MW). Figure 2-2 and Table 2-3 show the System LCOE calculation results for this scenario.

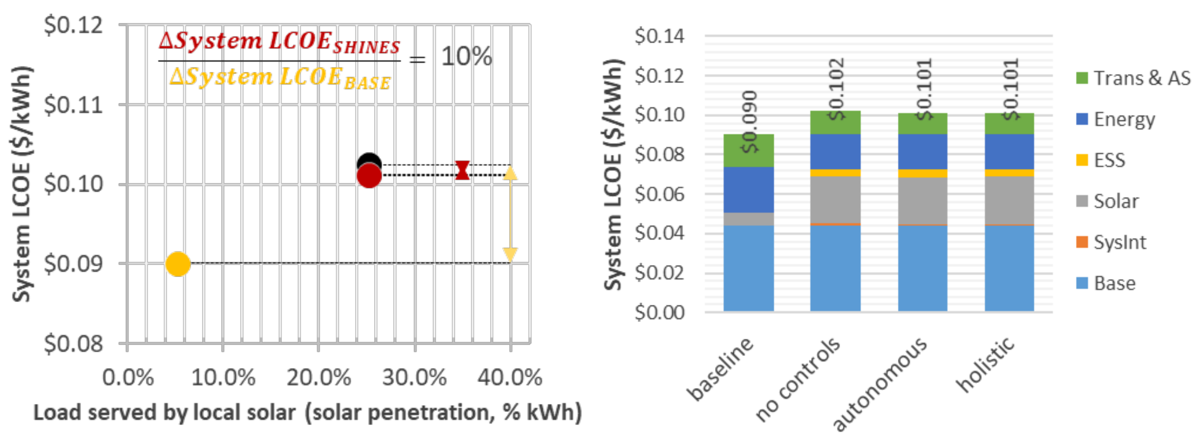


Figure 2-2 Scenario 2, Left: System LCOE results for each control strategy, Right: System LCOE breakdown

Table 2-3: Scenario 2; System LCOE results summary

Scenario	Baseline	No Controls	Autonomous	Holistic
Solar PV penetration by energy (%)	5%	25%	25%	25%
System LCOE to Serve Load ($/kWh)				
low DER costs, low ERCOT prices	$0.084	$0.093	$0.092	$0.092
low DER costs, high ERCOT prices	$0.096	$0.102	$0.101	$0.101
mod. DER costs, mod. ERCOT prices (charted in, Figure 2-2 left)	$0.090	$0.102	$0.101	$0.101
high DER costs, low ERCOT prices	$0.084	$0.105	$0.104	$0.104
high DER costs, high ERCOT prices	$0.096	$0.114	$0.112	$0.112
System LCOE to Serve Load by Category (mod. case charted in Figure 2-2, right)				
Base distribution system infrastructure	$0.044	$0.044	$0.044	$0.044
System integration	$-	$0.001	$0.000	$0.000
Solar CapEx and OpEx	$0.006	$0.024	$0.024	$0.024
ESS CapEx and OpEx	$-	$0.004	$0.004	$0.004
Net wholesale energy	$0.023	$0.018	$0.018	$0.018
Transmission and ancillary services	$0.016	$0.012	$0.011	$0.011

Compared to Scenario 1, in Scenario 2, both the System LCOE and the %delta metric are larger. Still, the difference between the System LCOE of the three control strategies is small, especially the difference between autonomous and holistic controls. Although System LCOE has increased compared to Scenario 1, the value captured through holistic controls has slightly increased (%delta metric is 10%), suggesting that in case of utility-scale ESS, holistic controls are more valuable for larger volumes of storage.

2.3.3 Comparison of Scenarios 1-4

Figure 2-3 and Figure 2-4 show the changes in the System LCOE (of holistic controls sub-scenario) and %delta metric as the capacity of utility-scale ESS increases in MU. Note that Scenario 4 deploys three 0.99MWh/2MWh ESS (6MWh in total). In addition to the System LCOE results of mod. DER costs, mod. ERCOT prices, the results of other variations of DER costs and ERCOT prices are also shown for comparison.

System LCOE increases almost linearly as the capacity of storage increases in the circuit. However, the rate of increase varies among different combinations of DER costs and ERCOT prices. For the same amount of storage, the low DER costs and low ERCOT prices case has the smallest, and the high DER costs and high ERCOT prices has the largest System LCOE among all variations.

The changes in %delta metric (Figure 2-4) are not linear. Although %delta metric increases as the amount of deployed storage increases, the rate of increase drops with an increase in the ESS capacity. This suggests that the value captured by holistic controls will, at some point, become saturated. Determining the ESS capacity for which the saturation occurs was not part of the economic optimization.

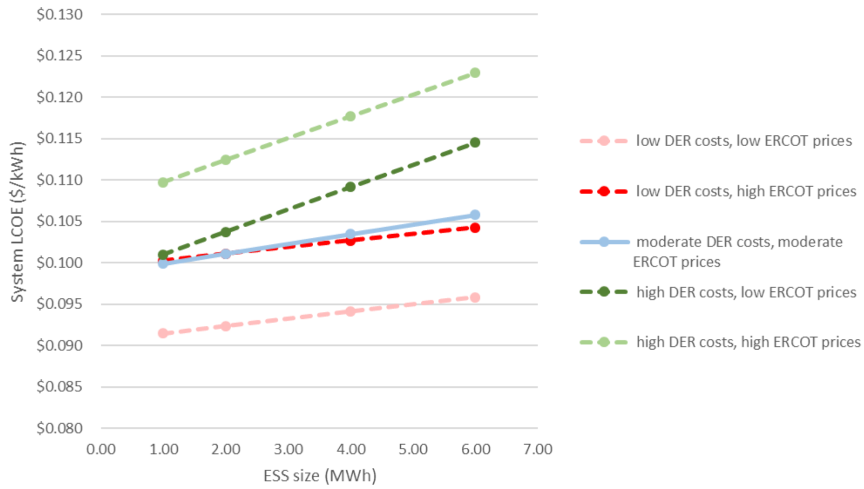


Figure 2-3 Comparison of holistic System LCOE for Scenarios 1-4

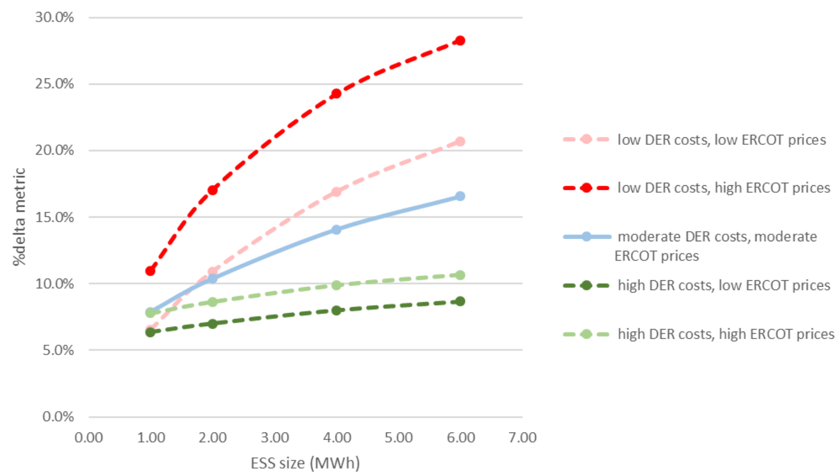


Figure 2-4 Comparison of %delta metric for Scenarios 1-4

Figure 2-4 shows that Scenario 3 meets the second SHINES criterion in the low DER costs, high ERCOT prices, while Scenario 4 meets the criterion in any variations with low DER costs. This indicates that at lower DER costs and higher ERCOT prices the differential value of holistic control becomes more tangible. At lower DER costs, Transmission and Ancillary Services costs become a larger cost component of System LCOE, and therefore, any reduction in this component results in a larger change in %delta metric. Also, at higher ERCOT prices (which include higher Transmission and Ancillary Service rates), PLR becomes even more valuable. Since holistic controls can fully capture the value of PLR, %delta metric is larger at higher ERCOT prices.

2.3.4 Scenario 5

Scenario 5 includes 500kW/1MWh of aggregated residential storage (in the form of 125 distributed residential ESS, each 4kW and 8kWh). The residential ESS are deployed to houses with solar generation. There are 1768 customer meters on the MU circuit, so 125 residential ESS translates to residential ESS uptake by 7% of residential customers on the circuit. Figure 2-5 and Table 2-4 show the System LCOE results for this Scenario. The case with holistic controls has the smallest System LCOE among the three control strategies, while autonomous controls have the poorest performance and largest System LCOE. This is because holistic controls fully and no controls partially capture the value of PLR, but autonomous controls do not. The following figures show the aggregate behavior of residential ESS during the 4CP intervals in 2016. The blue line represents ERCOT's system load and the red line shows the residential ESS aggregate output. Each plot represents a summer month, and the dashed lines mark the start and an end of the 4CP event in that month. In the case with no controls, Figure 2-6, the ESS charging and discharging follow Austin Energy's TOU rate schedule, discharging during peak hours (4pm-6pm) on a fixed schedule every day. In Figure 2-7, the autonomous controls case, the ESS monitor the net load at the customer meter and charge to avoid back-feeding, absorbing solar generation in excess of demand, and discharge when net metered load goes above a fixed threshold. In Figure 2-8, the holistic controls case, the ESS are aggregated and placed under DERO's command, and participate in wholesale market applications including PLR, RTPD, and EA. Each ESS is well below the 1MW threshold and able to participate in PLR as an unregistered generator. Since 4CP in ERCOT happened to occur during 4pm-6pm period 75% of times in 2016 (June, July and August, but not September), no controls could capture 75% of 4CP incidents, although it is not directly designed to do so. The autonomous control of residential ESS is designed to maximize self-consumption and therefore it fails to capture any PLR value and therefore shows the largest System LCOE.

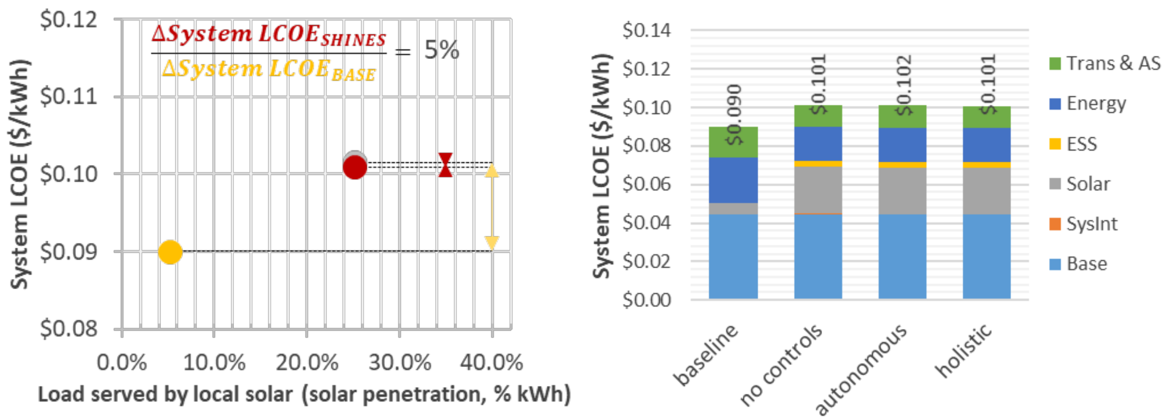


Figure 2-5 Scenario 5, Left: System LCOE results for each control strategy, Right: System LCOE breakdown

Table 2-4: Scenario 5; System LCOE results summary

Scenario	Baseline	No Controls	Autonomous	Holistic
Solar PV penetration by energy (%)	5%	25%	25%	25%
System LCOE to Serve Load ($/kWh)				
low DER costs, low ERCOT prices	$0.084	$0.093	$0.093	$0.092
low DER costs, high ERCOT prices	$0.096	$0.101	$0.102	$0.101
mod. DER costs, mod. ERCOT prices (charted in, Figure 2-5 left)	$0.090	$0.101	$0.102	$0.101
high DER costs, low ERCOT prices	$0.084	$0.103	$0.102	$0.102
high DER costs, high ERCOT prices	$0.096	$0.111	$0.111	$0.110
System LCOE to Serve Load by Category (mod. case charted in Figure 2-5, right)				
Base distribution system infrastructure	$0.044	$0.044	$0.044	$0.044
System integration	$-	$0.001	$0.000	$0.000
Solar CapEx and OpEx	$0.006	$0.024	$0.024	$0.024
ESS CapEx and OpEx	$-	$0.003	$0.003	$0.003
Net wholesale energy	$0.023	$0.018	$0.018	$0.018
Transmission and ancillary services	$0.016	$0.012	$0.012	$0.012

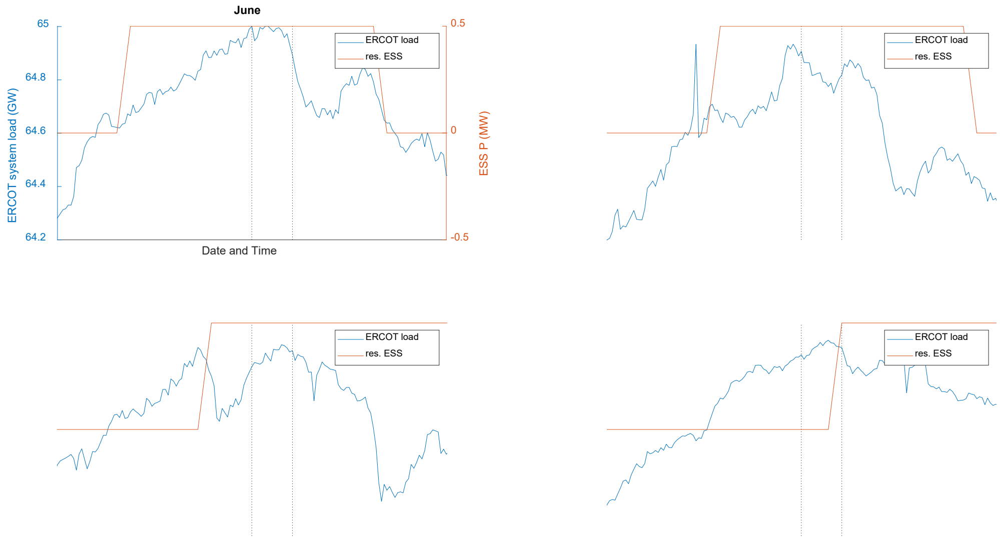


Figure 2-6 Aggregate behavior of residential ESS during 4CP incidents in 2016, No controls

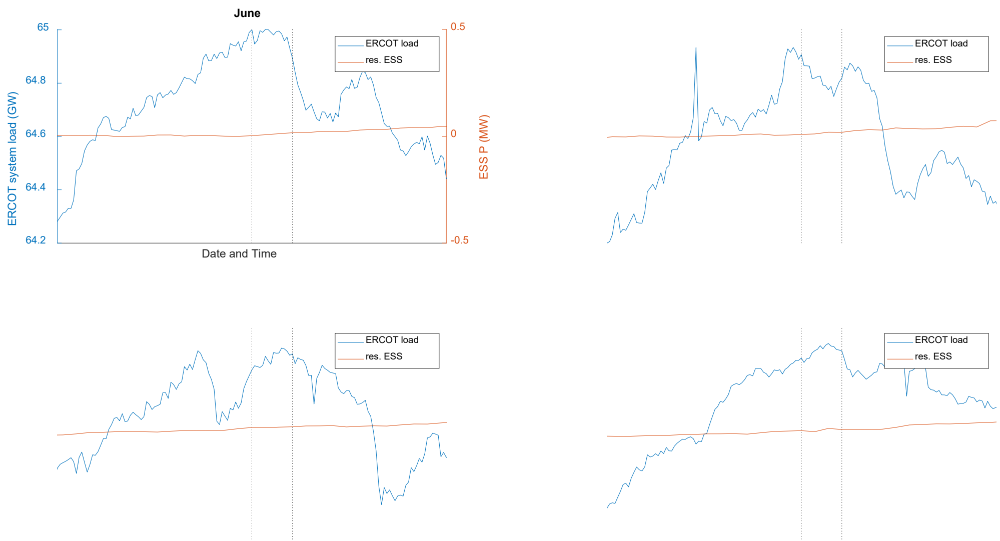


Figure 2-7 Aggregate behavior of residential ESS during 4CP incidents in 2016, Autonomous controls

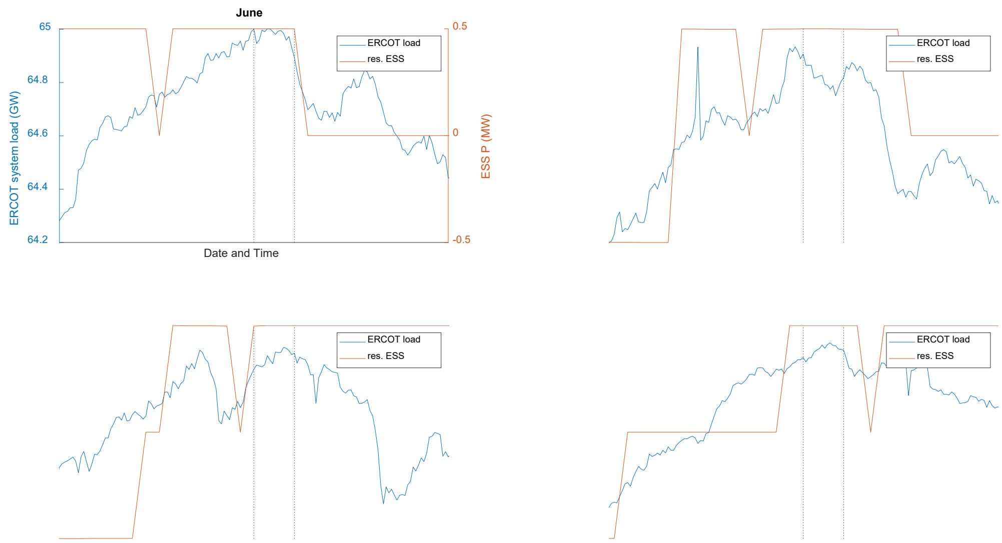


Figure 2-8 Aggregate behavior of residential ESS during 4CP incidents in 2016, Holistic controls

2.3.5 Scenario 7

Figure 2-9 and Table 2-5 pose similarities of Scenario 5 -with a 14 commercial ESS, each 36kW and 72kWh, for a total deployment of 500kW/1MW of ESS. Like Scenario 5, the holistic controls have the smallest System LCOE followed by no controls and the largest System LCOE was autonomous controls.

In the no controls case, the ESS follow the same fixed daily schedule based on the TOU rates as the residential ESS in the no controls case, and similarly to the residential case, garner value from load reduction during the 4CP intervals. In the autonomous controls case, the commercial ESS only do DCR. Due to lack of information available about the fielded SHINES DCR, the modeled DCR follows a simple 3-threshhold approach where the commercial ESS will start discharging when the load goes above the threshold. Thresholds were defined based on the seasonality of the load. Three distinguished seasons were observed in Austin Energy's system: the first shoulder season which starts in January and ends in May, the peak season, which starts in June and ends in September, and the second shoulder season which starts in October and ends in December. In the holistic controls case, the commercial ESS prioritize DCR and when they are not needed to carry out DCR, are aggregated and made available to DERO to carry out the wholesale market applications including PLR, RTPD, and EA. The exception is 2pm-6pm in summer months when DERO takes full control of commercial ESS to perform market applications, most importantly PLR. DERO needs the time period between 2pm-4pm to charge up the ESS and get ready for a possible 4CP incident.

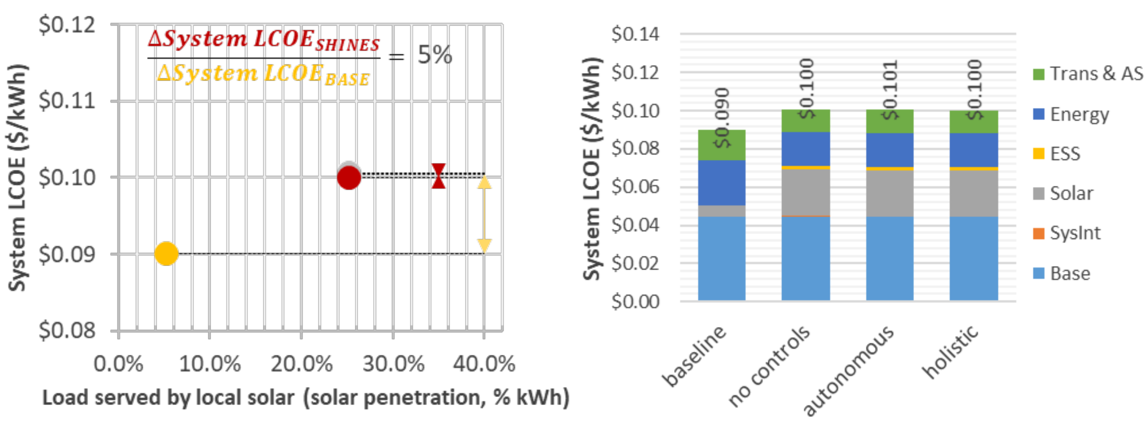


Figure 2-9 Scenario 7, Left: System LCOE results for each control strategy, Right: System LCOE breakdown

Table 2-5: Scenario 7; System LCOE results summary

Scenario	Baseline	No Controls	Autonomous	Holistic
Solar PV penetration by energy (%)	5%	25%	25%	25%
System LCOE to Serve Load ($/kWh)				
low DER costs, low ERCOT prices	$0.084	$0.092	$0.092	$0.091
low DER costs, high ERCOT prices	$0.096	$0.100	$0.101	$0.100
mod. DER costs, mod. ERCOT prices (charted in, Figure 2-9 left)	$0.090	$0.100	$0.101	$0.100
high DER costs, low ERCOT prices	$0.084	$0.101	$0.101	$0.100
high DER costs, high ERCOT prices	$0.096	$0.110	$0.110	$0.109
System LCOE to Serve Load by Category (mod. case charted in Figure 2-9, right)				
Base distribution system infrastructure	$0.044	$0.044	$0.044	$0.044
System integration	$-	$0.001	$0.000	$0.000
Solar CapEx and OpEx	$0.006	$0.024	$0.024	$0.024
ESS CapEx and OpEx	$-	$0.002	$0.002	$0.002
Net wholesale energy	$0.023	$0.018	$0.018	$0.018
Transmission and ancillary services	$0.016	$0.012	$0.012	$0.012

DCR is a customer-focused application and is designed to reduce the customer bill from Austin Energy. It does this by discharging ESS to reduce the metered net load when the customer's load is highest. For some customers, depending on the customer load shape, this may coincide with time intervals with high wholesale energy costs or with the 4 ERCOT system coincident peaks. Because the System LCOE metric does not explicitly calculate the value of transactions that occur solely within the system boundary, the reduction in the customer bill is not directly calculated or included in the System LCOE value. To the extent that DCR leads to changes in the fundamental costs, such as circuit infrastructure or reduction in net wholesale market costs, that will be reflected by a reduced System LCOE result.

If the 2pm-6pm window is not reserved for DERO market operations in summer, DCR will charge and discharge the ESS based on the customer's needs. Since customer's peak load does not necessarily coincide with the ERCOT 4CP events, giving priority to DCR during those hours may lead to a significant loss of value as the ESS will not provide PLR.

2.3.6 Comparison of Single-Technology Scenarios

Figure 2-10 and Figure 2-11 compare the System LCOE and %delta metric of single-technology scenarios (Scenarios 1-2, 5-6, and 7-8) when the amount of storage increases from 1MWh to 2MWh. Figure 2-10 shows that for the same amount of storage, residential ESS has the largest System LCOE. Also, residential ESS has the largest incremental System LCOE when the amount of storage increases from 1MWh to 2MWh. Utility-Scale ESS remains the cheapest technology followed by commercial ESS. The System LCOE and incremental System LCOE of utility-scale and commercial ESS are very close to each other in these scenarios.

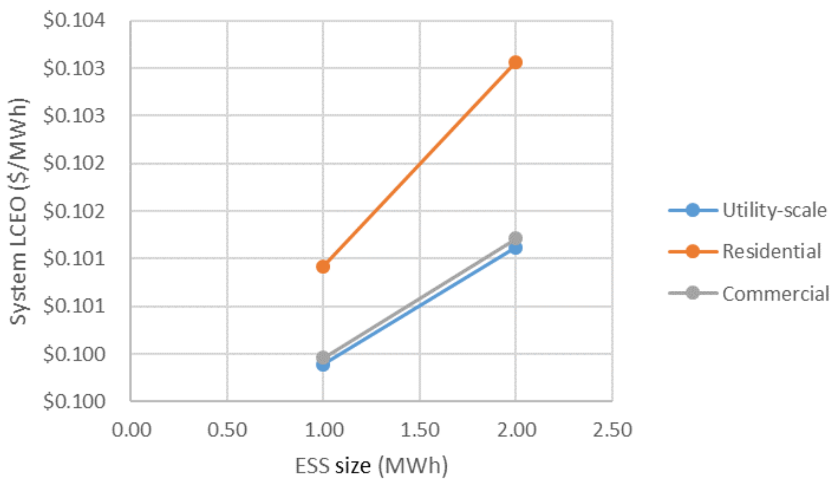


Figure 2-10 Comparison of System LCOE for single-technology scenarios

Figure 2-11 show how %delta metric changes as the amount of storage increases for the same single-technology. The incremental %delta metric is largest for utility-scale ESS. The increase in %delta metric is much smaller for residential and commercial storage, mainly because no controls can capture most of the PLR value without additional cost of using a fleet manager. Overall, holistic controls appear to be more beneficial when applied to utility-scale storage, compared to residential and commercial storage.

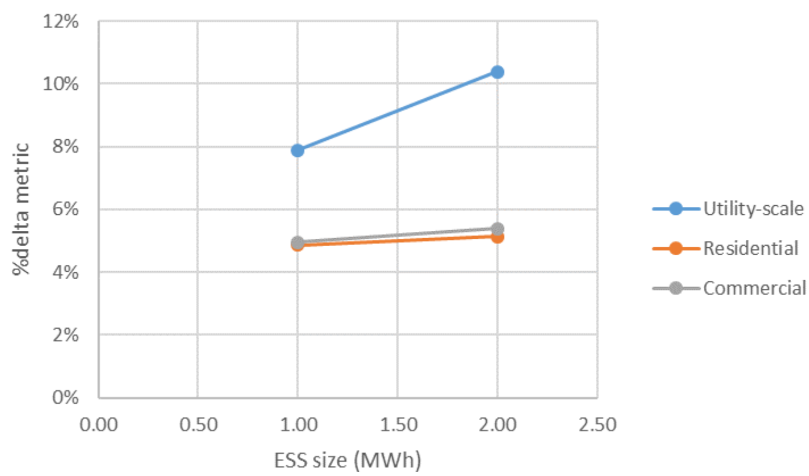
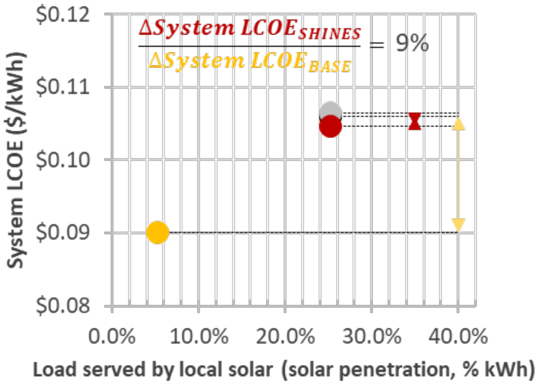


Figure 2-11 Comparison of %delta metric for single-technology scenarios

2.3.7 Scenario 9

Figure 2-12 and Table 2-6 show the System LCOE results for Scenario 9 which deploys a mixture of utility-scale, residential and commercial storage. This scenario is in fact a combination of Scenarios 2, 5 and 7 and includes 4MWh of storage, 2MWh of which is utility-scale, 1MWh residential and 1 MWh commercial. Compared to Scenario 3 which had the same amount of storage but purely in the form of utility-scale storage, Scenario 9 has a larger System LCOE, and smaller %delta metric. This means Scenario 3, with 4MWh of utility-scale storage, is less expensive and a better value than Scenario 9, with its mixture of storage types. Also, similar to scenarios with pure residential or pure commercial storage, in this scenario, autonomous controls have the largest System LCOE among the three control strategies, which shows that this mixture-of-technologies scenario carries the combined characteristics of each individual technology.



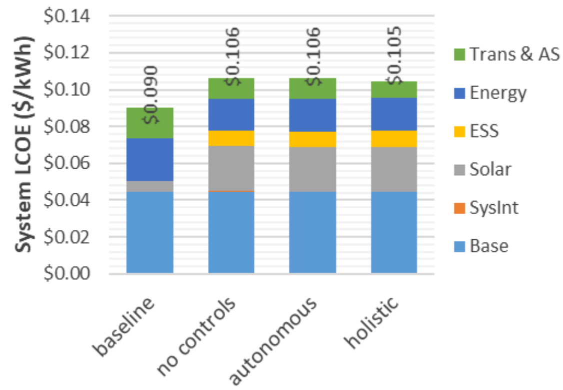


Figure 2-12 Scenario 9, Left: System LCOE results for each control strategy, Right: System LCOE breakdown

Table 2-6: Scenario 9; System LCOE results summary

Scenario	Baseline	No Controls	Autonomous	Holistic
Solar PV penetration by energy (%)	5%	25%	25%	25%
System LCOE to Serve Load ($/kWh)				
low DER costs, low ERCOT prices	$0.084	$0.096	$0.097	$0.095
low DER costs, high ERCOT prices	$0.096	$0.105	$0.105	$0.104
mod. DER costs, mod. ERCOT prices (charted in, Figure 2-12 left)	$0.090	$0.106	$0.106	$0.105
high DER costs, low ERCOT prices	$0.084	$0.111	$0.111	$0.109
high DER costs, high ERCOT prices	$0.096	$0.120	$0.120	$0.118
System LCOE to Serve Load by Category (mod. case charted in Figure 2-12 right)				
Base distribution system infrastructure	$0.044	$0.044	$0.044	$0.044
System integration	$-	$0.001	$0.000	$0.000
Solar CapEx and OpEx	$0.006	$0.024	$0.024	$0.024
ESS CapEx and OpEx	$-	$0.008	$0.009	$0.009
Net wholesale energy	$0.023	$0.018	$0.018	$0.018
Transmission and ancillary services	$0.016	$0.011	$0.011	$0.009

2.3.8 Scenario 10

Figure 2-13 and Table 2-7 show the System LCOE results for Scenario 10 which deploys 1MWh of utility-scale storage, 2MWh residential, and 1MWh commercial. Similar to Scenario 1, 6 and 7 -Scenario 10 also shows the combined characteristics of each individual technology. Compared to Scenario 9, the System LCOE is larger and the %delta metric is smaller. This is mainly because in Scenario 10, the dominant technology (in terms of volume) is residential storage which is the most expensive technology among the three available storage options, whereas in Scenario 9, utility-scale storage carries more weight compared to residential and commercial technologies.

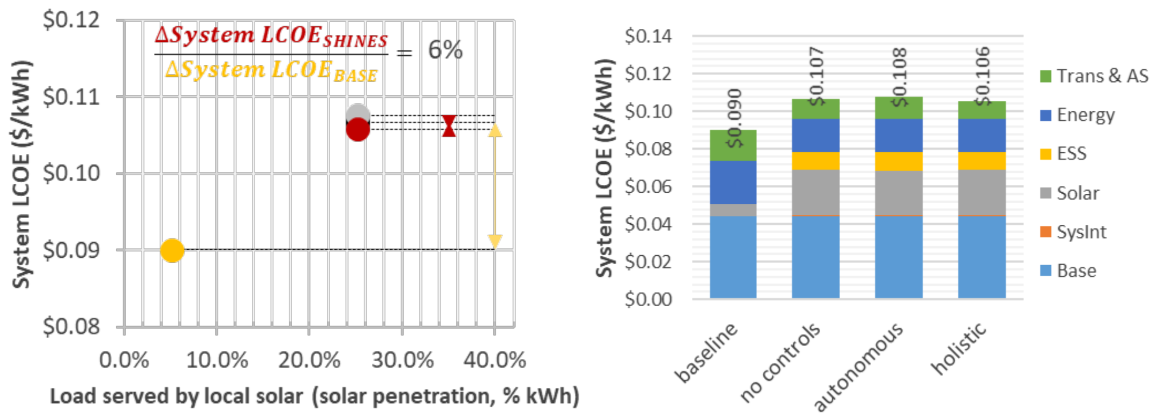


Figure 2-13 Scenario 10, Left: System LCOE results for each control strategy, Right: System LCOE breakdown

Table 2-7: Scenario 10; System LCOE results summary

Scenario	Baseline	No Controls	Autonomous	Holistic
Solar PV penetration by energy (%)	5%	25%	25%	25%
System LCOE to Serve Load ($/kWh)				
low DER costs, low ERCOT prices	$0.084	$0.097	$0.098	$0.096
low DER costs, high ERCOT prices	$0.096	$0.105	$0.106	$0.105
mod. DER costs, mod. ERCOT prices (charted in, Figure 2-13 left)	$0.090	$0.107	$0.108	$0.106
high DER costs, low ERCOT prices	$0.084	$0.111	$0.112	$0.110
high DER costs, high ERCOT prices	$0.096	$0.120	$0.120	$0.119
System LCOE to Serve Load by Category (mod. case charted in Figure 2-13 right)				
Base distribution system infrastructure	$0.044	$0.044	$0.044	$0.044
System integration	$-	$0.001	$0.000	$0.000
Solar CapEx and OpEx	$0.006	$0.024	$0.024	$0.024
ESS CapEx and OpEx	$-	$0.009	$0.010	$0.010
Net wholesale energy	$0.023	$0.018	$0.018	$0.018
Transmission and ancillary services	$0.016	$0.010	$0.012	$0.009

2.3.9 Scenario 11

Figure 2-14 and Table 2-8 show the System LCOE results for Scenario 11 which is a combination of Scenarios, 1, 5 and 8 and deploys 1MWh of utility-scale storage, 1MWh residential and 2MWh commercial. Compared to Scenarios 9 and 10, this scenario has a smaller System LCOE, but its %delta metric is smaller than Scenario 9 and larger than Scenario 10. Similar to Scenarios 9 and 10, Scenario 11 shows the combined characteristics of individual technologies, but this time the behavior is skewed toward commercial storage.

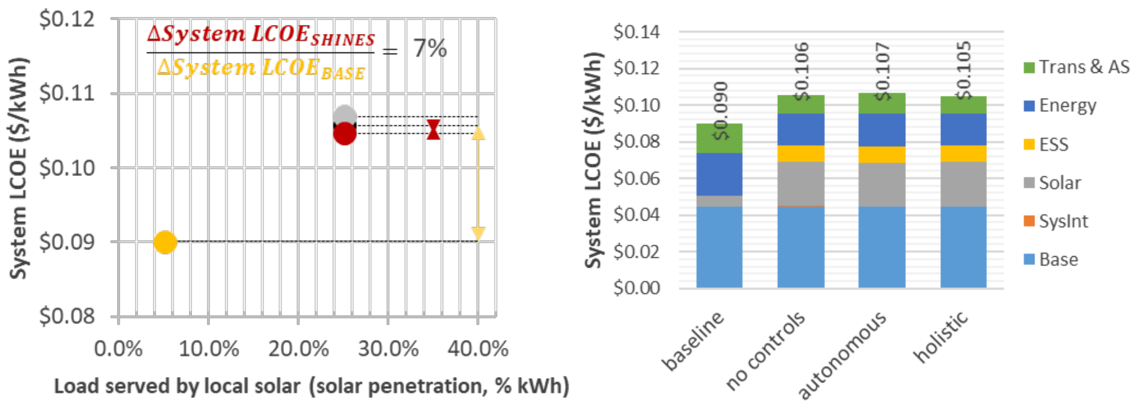


Figure 2-14 Scenario 11, Left: System LCOE results for each control strategy, Right: System LCOE breakdown

Table 2-8: Scenario 11; System LCOE results summary

Scenario	Baseline	No Controls	Autonomous	Holistic
Solar PV penetration by energy (%)	5%	25%	25%	25%
System LCOE to Serve Load ($/kWh)				
low DER costs, low ERCOT prices	$0.084	$0.096	$0.097	$0.095
low DER costs, high ERCOT prices	$0.096	$0.105	$0.106	$0.104
mod. DER costs, mod. ERCOT prices (charted in, Figure 2-14 left)	$0.090	$0.106	$0.107	$0.105
high DER costs, low ERCOT prices	$0.084	$0.110	$0.111	$0.109
high DER costs, high ERCOT prices	$0.096	$0.118	$0.119	$0.117
System LCOE to Serve Load by Category (mod. case charted in Figure 2-14 right)				
Base distribution system infrastructure	$0.044	$0.044	$0.044	$0.044
System integration	$-	$0.001	$0.000	$0.000
Solar CapEx and OpEx	$0.006	$0.024	$0.024	$0.024
ESS CapEx and OpEx	$ -	$0.009	$0.009	$0.009
Net wholesale energy	$0.023	$0.018	$0.018	$0.018
Transmission and ancillary services	$0.016	$0.010	$0.012	$0.009

For a 1 or 2MWh of storage deployment, commercial and utility-scale ESS have similar System LCOE as discussed in Section 2.3.6. Therefore, the System LCOE of Scenarios 9 and 11 should be similar to each other, which is the case here. Although utility-scale storage has a slightly better performance compared to commercial in the single-technology cases, Scenario 11 has a slightly smaller System LCOE (the difference can only be seen on the 4th decimal place). This is because in Scenario 11, a smaller amount of energy is imported into the system compared to Scenario 9. However, the difference is not significant.

Scenario 4 which has the same amount of storage as Scenarios 9-11, has a smaller System LCOE. Again, this shows that utility-scale storage is the more economical option in the case of Austin SHINES.

2.3.10 Comparison of 4MWh Scenarios

In Scenarios 3, 9, 10, and 11 (summarized again in Table 2-9), there is a total of 4MWh of ESS.

Table 2-9: List of 4MWh scenarios and their asset mixes

Scenario	Solar penetration by energy (%)	Distributed solar (MW)	Community solar (MW)	Utility ESS (MWh)	Residential ESS (MWh)	Commercial ESS (MWh)	EV (MWh)	Load Control
3	25	4.9	0	4	0	0	0	No
9	25	4.9	0	2	1	1	0	No
10	25	4.9	0	1	2	1	0	No
11	25	4.9	0	1	1	2	0	No

Understanding the lowest System LCOE and highest %delta would be located in the lower right quadrant of the graph, Figure 2-15 demonstrates Scenario 3 as the best. With all 4MWh being Utility ESS, this configuration beats all other mixes by both metrics.

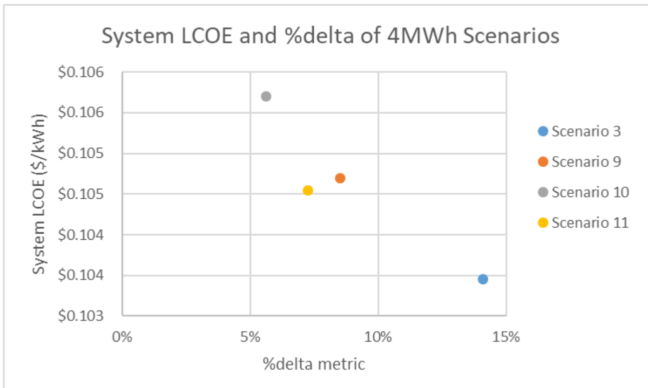


Figure 2-15 Comparison of 4MWh Scenarios SHINES metrics

2.3.11 Scenario 12

Figure 2-16 and Table 2-10 show the results of System LCOE calculations for Scenario 12 which includes 1.8MW of distributed solar and a 3.2MW community solar co-located with a 0.99MW/2MWh utility-scale ESS. The ESS is assumed to be installed at the same node as the fielded MU ESS. In this setup, the solar penetration is still 25%, but half the solar generation comes from distributed solar (existing and additional) and the other half (12.5%) comes from community solar. Compared to Scenario 2 which has the same type and volume of storage and solar penetration, Scenario 12 has a larger System LCOE and a similar %delta metric. A comparison between Table 2-3 and Table 2-10 show that in Scenario 12, the cost of additional solar is less than that of Scenario 2 (community solar is cheaper than distributed solar), but the Transmission and Ancillary Service costs are higher. This is because the capacity of the community solar plant in this case is larger than 1MW, and therefore it cannot contribute to PLR. This loss of value offsets the cost difference between community and distributed solar.

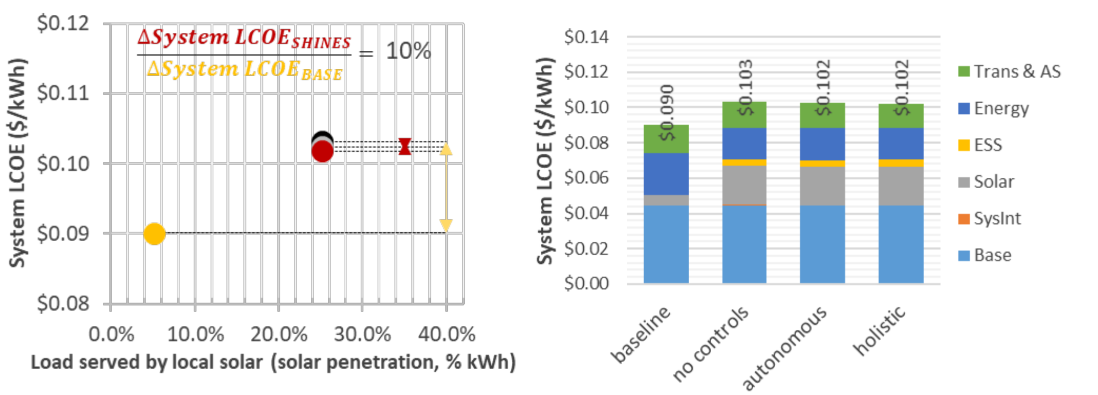


Figure 2-16 Scenario 12, Left: System LCOE results for each control strategy, Right: System LCOE breakdown

Table 2-10: Scenario 12; System LCOE results summary

Scenario	Baseline	No Controls	Autonomous	Holistic
Solar PV penetration by energy (%)	5%	25%	25%	25%
System LCOE to Serve Load ($/kWh)				
low DER costs, low ERCOT prices	$0.084	$0.094	$0.094	$0.093
low DER costs, high ERCOT prices	$0.096	$0.104	$0.103	$0.102
mod. DER costs, mod. ERCOT prices (charted in, Figure 2-16 left)	$0.090	$0.103	$0.102	$0.102
high DER costs, low ERCOT prices	$0.084	$0.105	$0.104	$0.104
high DER costs, high ERCOT prices	$0.096	$0.114	$0.113	$0.113
System LCOE to Serve Load by Category (mod. case charted in Figure 2-16 right)				
Base distribution system infrastructure	$0.044	$0.044	$0.044	$0.044
System integration	$-	$0.001	$0.000	$0.000
Solar CapEx and OpEx	$0.006	$0.022	$0.022	$0.022
ESS CapEx and OpEx	$-	$0.004	$0.004	$0.004
Net wholesale energy	$0.023	$0.018	$0.018	$0.018
Transmission and ancillary services	$0.016	$0.015	$0.014	$0.013

2.3.12 Scenario 13

Scenario 13 includes 2MWh of residential storage provided through EVs only. The following assumptions were made for this analysis:

- Only residential EV charging stations (multi-family or single-family) are included in the analysis. Public chargers (workplace, grocery stores, etc.) and fast DC chargers are not considered.
- A typical EV has a battery capacity of 40 kWh, travels 10,000 miles per year and consumes 0.4kWh per mile.
- The average nominal power of a residential charger is 7kW.
- The number of EVs existing in MU circuit accounts for 0.5% of total number of cars in Austin area. This assumption is made based on the ratio of MU circuit load to Austin Energy load in 2016[1].
- Not all EVs are controllable. The uncontrollable portion of EVs are assumed to be part of the system load and not the storage capacity.
- V2G mode is only available in the holistic controls sub-scenarios. Vehicles are assumed to be charge-only in the no controls and autonomous controls sub-scenarios. Details of each control strategy are discussed in FD-1.
- Availability of EVs for providing grid services is modeled as described in Section 2.3.12.1
- V2G provision has two cost components. The first component is associated with battery degradation. Although the car battery can degrade when discharging for grid services, infrequent provision of V2G services, especially for

[1] MU circuit peak demand to AE peak demand = 9MW:2,761MW (0.33%). MU circuit total energy consumption to AE total energy consumption = 34,740 MWh:13,465,066 MWh (0.26%). Rounded up to 0.5%

applications such as peak load reduction does not cause a significant wear and tear[2]. The second component is the cost of a bidirectional charger to enable V2G services. In this work, it is assumed that the EVs have built-in bidirectional inverters and there is no need to install an external bidirectional charger. According to an analysis by Pecan Street, the cost of a bidirectional commercial charger will be around $25,000, whereas the cost of a residential scale product will be between $4,500 and $5,500[3]. Initial evaluation showed that at low penetration of EVs, neither the commercial nor the residential product are cost effective, which makes V2G economically inviable.

2.3.12.1 *EV availability*

Mobile energy storage capacity of EVs can be used for providing various grid services. The biggest challenge with controlling mobile storage is in the stochasticity of availability. The availability varies over time and depends on numerous factors, including the commute pattern and charging behavior of EV owners. Some EV owners have more predictable behavior than others. EVs with more predictable behavior are better candidates for providing grid services. There are two components of availability: the number of available EVs, and the State of Charge (SOC) of the battery of each available EV.

In this work, the randomness associated with the number of EVs is modeled in two ways:

- The fixed availability model, which assumes that at any moment, a certain percentage of EVs are available for providing grid services. Note that this assumption does not mean that a specific set of cars is always available at all time. It simply means that at any moment, out of the pool of all EVs, at least a certain percentage of them are available for control.
- The variable availability model, which assumes a variability profile for the population of EVs. In this model the percentage of available cars changes as a function of time of day.

The randomness associated with SOC is even more complex, because it depends on numerous factors such as the initial SOC, commute pattern, charge pattern, and customers' constraints on the available SOC after providing grid services. These variables are highly customer dependent and adding them to the randomness model significantly increases the dimension and computation complexity of the analysis. To simply the problem, it is assumed that the SOC of available cars is 50%. The reason behind this assumption is explained later in this section.

Fixed Availability Model

FAM simply assumes that at any moment 40% of all V2G cars are available for V2G services, and the average SOC of those cars is 50%. This is equivalent to 20% of total mobile storage being available for providing grid services.

Variable Availability Model

VAM uses Pecan Street historical EV data to determine the aggregate availability of a population of EVs. This data belongs to 26 residential charging stations in 2018. Figure 2-17 shows the 1-year charge power time-series data of each of these EVs. Note that the plots share the x- and y- axes. Figure 2-18 shows the histogram of daily charge behavior for same EVs. These histograms are calculated using the same 1-year time-series data. At any time during the day, if the recorded charge power is above a certain threshold (0.1 kW) a charge event will be assigned to that time. The threshold is used because the metered data contains a level of measurement noise (very small power measurements that are not due to EV charging). Then, for each time of day (for each 15-minute interval) the number of charge events is counted and divided by the total number of charge events in 2018 for that car. Separate profiles are created for weekdays and weekends. Overall, the probability of a car being charged during any 15-min interval throughout the day is small (5-10% maximum). However, some customers have more predictable behavior than others. Also, for most customers the probability of charging is higher from 4pm to midnight. The charging behavior is even less predictable on the weekends.

[2] Wang D, Coignard J, Zeng T, Zhang C, Saxena S. "Quantifying electric vehicle battery degradation from driving vs. vehicle-to-grid services," *Journal of Power Sources*. 2016 Nov 15; 332:193-203.

[3] Pecan St. Inc "Vehicle to Grid (V2G) 2020 Cost Estimate Projections and Test Plan," 2018.

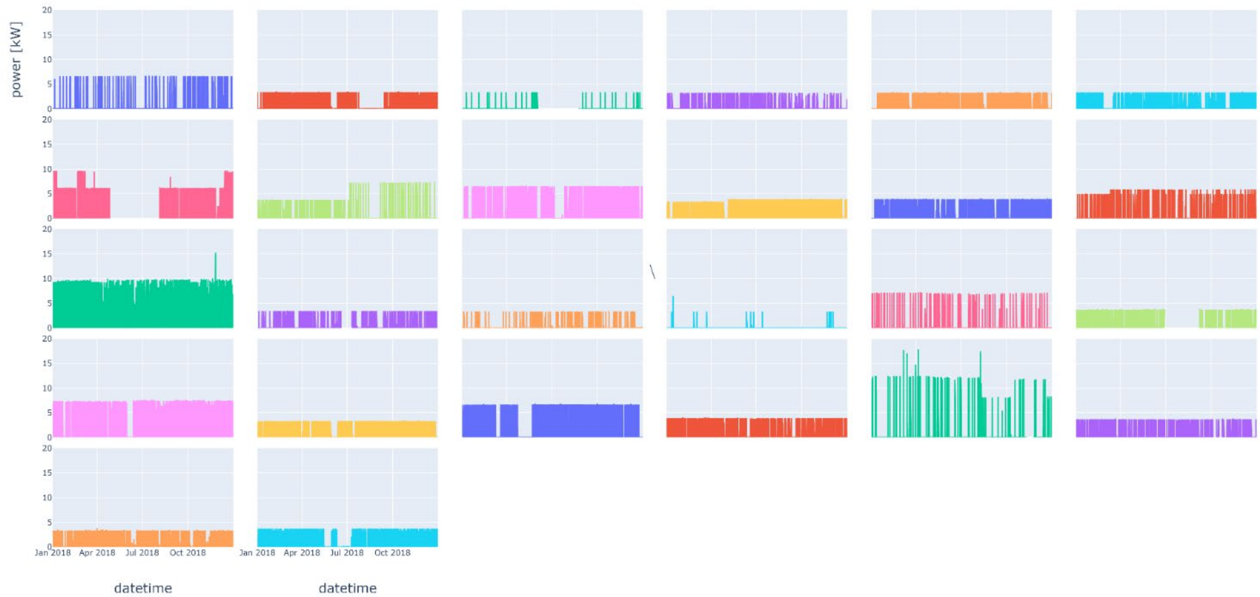


Figure 2-17 2018 charge power time-series data of Pecan Street EVs

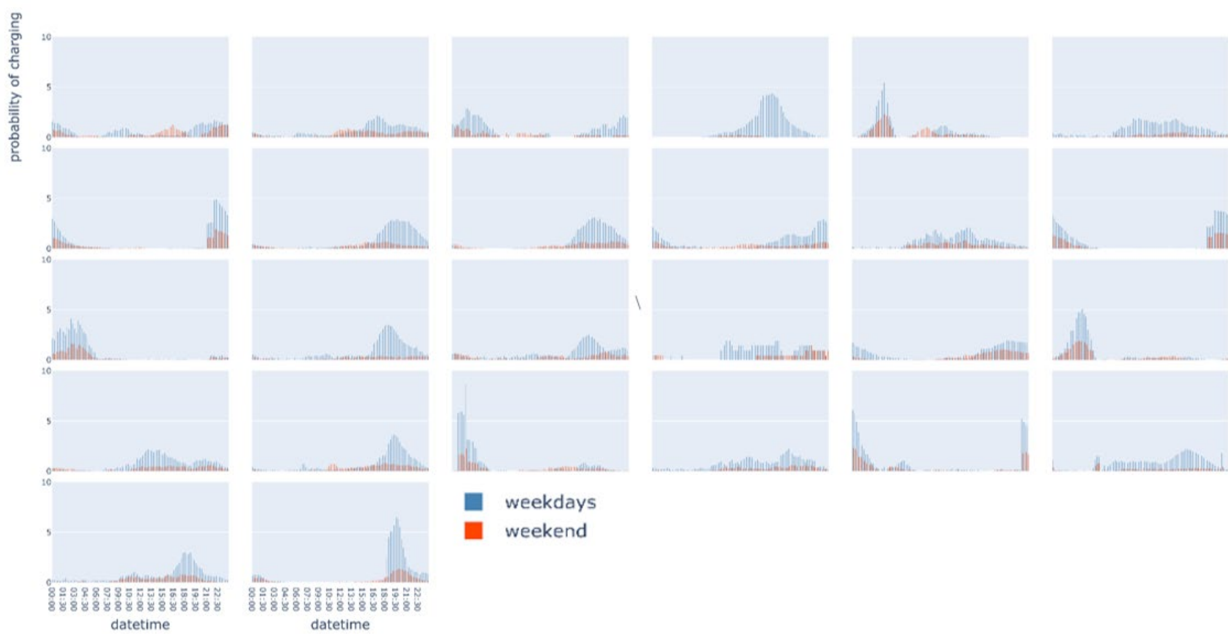


Figure 2-18 Daily charge probability profile for each Pecan Street EVs

Figure 2-19 shows the aggregate behavior of the entire Pecan Street EV fleet. The top left plot shows the 1-year aggregate charge power time-series data. The top right plot shows the 1-year average charge power time-series data. The average daily charge power for the entire fleet is shown the bottom left plot. These three plots all show that the aggregate availability is spread out throughout the day. The aggregate and average charge power are low considering the number of cars and the individual charge power shown in Figure 2-17. The bottom right plot shows the histogram of total annual energy usage for the population of EVs. The average consumption is 2.17MWh, which is slightly over half of the expected energy consumption for a typical EV with a 40kWh battery and an average of 1000 miles of commute per year. Since the Pecan Street EVs seem to have shorter than average commute (almost half), it is expected that the SOC of the batteries is at 50% on average (assuming that the consumers charge their EVs only at home).

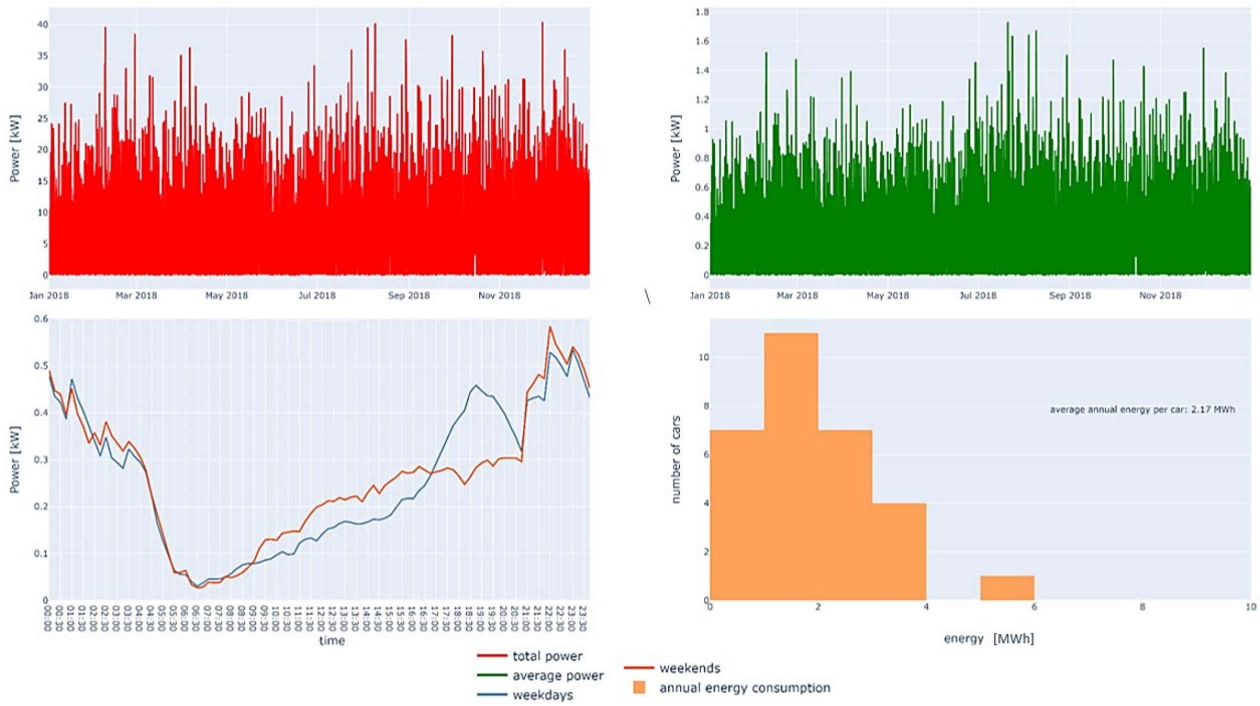


Figure 2-19 Aggregate behavior of Pecan Street EVs; top left: aggregate charge power, top right, average charge power, bottom left: average daily charge power, bottom right: histogram of total annual energy consumption

The top plot in Figure 2-20 shows the 15-min availability of the fleet throughout the year. The bottom plot shows the daily availability profile of the fleet. The availability peaks around 6pm during the week. The availability profile is flatter on weekends and peaks around 9pm. Maximum availability is 14%. Meaning that at best, 14% of EVs are available for V2G services. Since the SOC is assumed to be 50%, then only 7% of total EV battery capacity can be used for V2G.

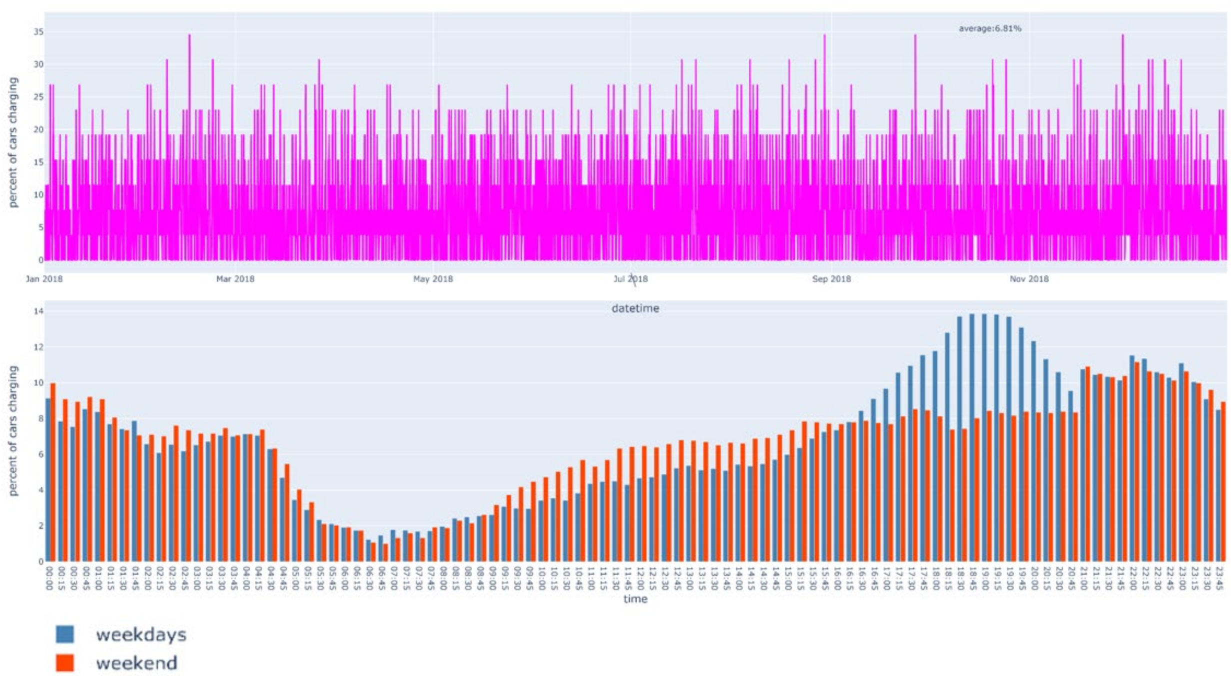


Figure 2-20 Percent of car charging; top: annual, bottom: average dailyEV data for each control strategy

<u>EV penetration</u>

Figure 2-21 shows EPRI's EV projections for the Austin area. For the year 2020, low, medium and high projections are 9500, 17750, and 36750 respectively. However, in 2019, there were 8697 registered EVs in Austin Energy's service territory which suggests that the number of EVs in 2020 will be closer to the low projection.

Later, Table 2-11 shows the maximum available capacity for each projection scenario. Note that even for the high penetration scenario, the aggregate EV battery capacity and power in MU are small. These values become even smaller after VAM and FAM are applied. The limited available power can be unfavorable for applications such as PLR in which the assets' contribution is calculated based on the power the assets provide and not just their energy production.

For Scenario 13, it is assumed that there are 10,000 EVs in Austin Energy's service territory which is very close to the realized projection in 2019. Also, it yields a total battery capacity of 2MWh which makes comparison with other scenarios more straightforward. Note that this scenario only uses FAM, because in case of VAM the available V2G capacity will be very small and the impact on System LCOE will be insignificant.

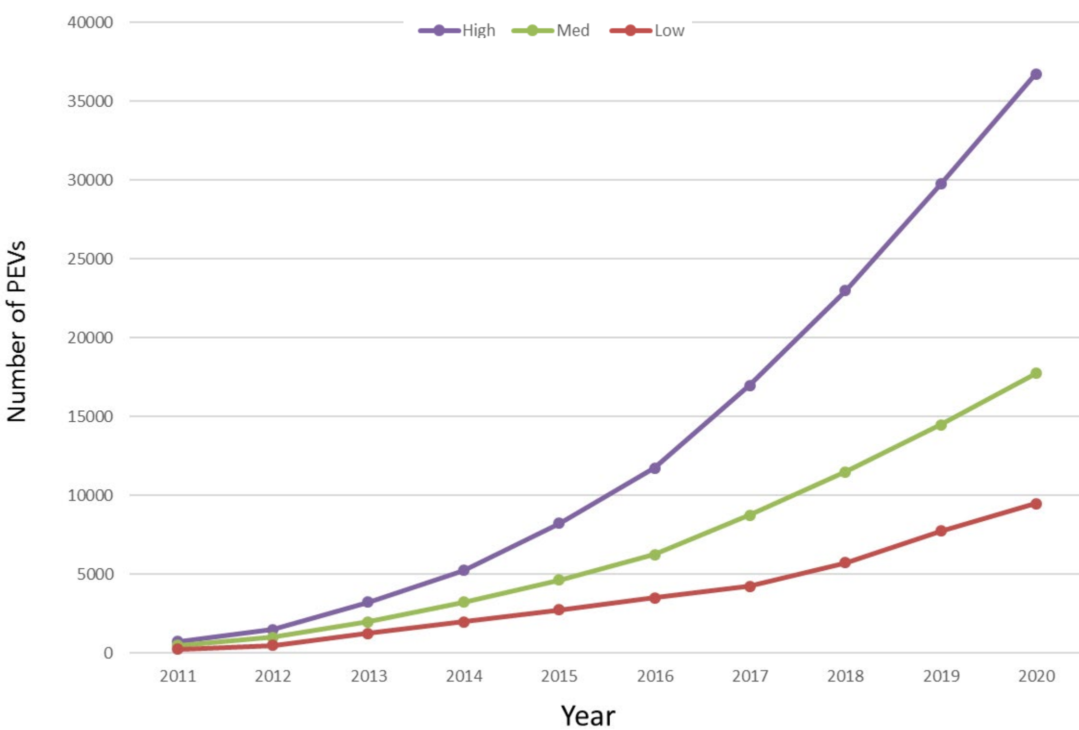


Figure 2-21 EPRI's projections on the number of plugged in EVs in Austin Energy's service territory

Scenario 13 uses the following data composition for each control sub-scenario:

- no controls: Pecan Street data, aggregated and scaled
- autonomous controls: Austin Energy's EV360 program data from 2 single-family locations, aggregated and scaled.
- holistic controls: For unavailable EVs (60% of V2G cars), the combination of the above two data sets, aggregated and scaled. The available EVs (40% of cars) act as aggregate residential storage, which follows DERO commands.

2.3.12.2 *System LCOE calculations for Scenario 13*

Figure 2-22 and Table 2-12 the System LCOE results for Scenario 13. Compared to similar scenarios with 2MWh of storage (Scenarios 2, 6 and 8), this scenario has a smaller System LCOE (reference Table 2-1). This is mainly because the 2MWh storage capacity comes at no costs. Also, the impact of EVs on Energy and Transmission and Ancillary

Service cost components is very small, mainly because of the low penetration of EVs and their limited availability for V2G services. Although the difference between the System LCOE of the three control strategies is small, Table 2-12 shows that the autonomous controls have the best performance in this scenario suggesting that, at least in lower penetration of EVs, TOU pricing is an effective control strategy for EVs.

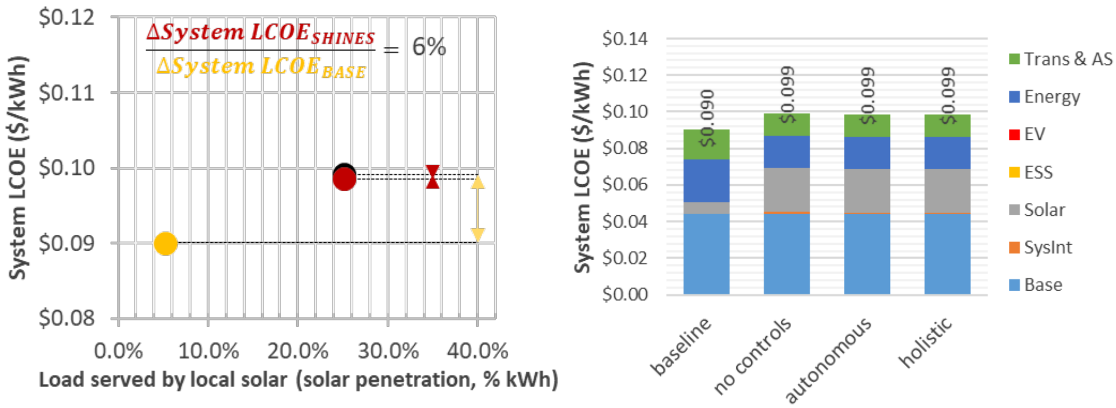


Figure 2-22 Scenario 13, Left: System LCOE results for each control strategy, Right: System LCOE breakdown

Table 2-11: Available battery capacity for different projection scenarios

Projection Scenario	Projected # of EVs in AE	Estimated # of EVs in MU	Total battery capacity in MU [MWh]	Total battery power in MU [MW]	Max. V2G power [MW]: FAM	Max. V2G power [MW]: VAM	Max. V2G energy [MWh]: FAM	Max. V2G energy [MWh]: VAM
Low	9500	48	1.9	0.3	0.1	0.05	0.4	0.1
Scenario 13	10000	50	2	0.4	0.1	0.05	0.4	0.1
Medium	17750	89	3.6	0.6	0.3	0.09	0.7	0.3
High	36750	184	7.4	1.3	0.5	0.20	1.5	0.5

Table 2-12: Scenario 13; System LCOE results summary

Scenario	Baseline	No Controls	Autonomous	Holistic
Solar PV penetration by energy (%)	5%	25%	25%	25%
System LCOE to Serve Load ($/kWh)				
low DER costs, low ERCOT prices	$0.084	$0.091	$0.090	$0.090
low DER costs, high ERCOT prices	$0.096	$0.100	$0.099	$0.099
mod. DER costs, mod. ERCOT prices (charted in Figure 2-22 left)	$0.090	$0.099	$0.099	$0.099
high DER costs, low ERCOT prices	$0.084	$0.099	$0.098	$0.098
high DER costs, high ERCOT prices	$0.096	$0.108	$0.107	$0.107
System LCOE to Serve Load by Category (mod. case charted in Figure 2-22 right)				
Base distribution system infrastructure	$0.044	$0.044	$0.044	$0.044
System integration	$-	$0.001	$0.000	$0.000
Solar CapEx and OpEx	$0.006	$0.024	$0.024	$0.024

ESS CapEx and OpEx	$-	$-	$-	$-
EV CapEx and OpEx	$-	$-	$-	$-
Net wholesale energy	$0.023	$0.018	$0.018	$0.018
Transmission and ancillary services	$0.016	$0.012	$0.012	$0.012

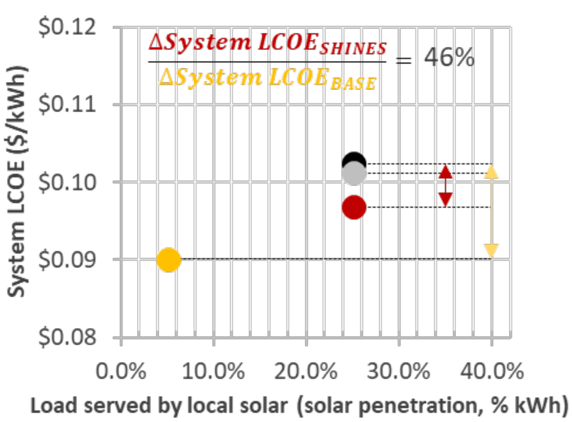
2.3.13 Scenario 14

Scenario 14 includes 2MWh of utility-scale storage and applies a load control algorithm to residential loads to reduce the peak demand. The load control algorithm shifts energy usage of three controllable, high-consumption residential devices to off-peak hours: HVAC systems, Electric Water Heaters (EWHs), and Pool Pumps (PPs). Within the load control tool, each type of controllable load is given a priority ranking, so that users can specify which kinds of loads residential customers would most like to use during peak times. The target load profile for each day is calculated by distributing the total energy consumption during that day equally over 5-minute intervals in that day.

The steps of the algorithm are as follows:

- EWH, PP, and HVAC loads are ranked (1-3) according to priority. This is the priority to not shift the load. That is, priority 3 loads are most likely to shift.
- The algorithm starts with the highest priority demand on the first day of the year. Available load for any time interval is the delta between the uncontrollable load and the target load profile. In each time interval, if available load is greater than the total aggregate load of the specific appliance then the load is assigned to that step. Otherwise, the load is moved to the next time step where available load is greater.
- if the algorithm reaches the last time step and the load has still not been assigned, it is allocated to the time step with the least demand.
- the process is repeated for the remaining appliance loads in order of priority.
- the algorithm is repeated for all days of the year.

Figure 2-23 and Table 2-13 show the System LCOE results for Scenario 14. It is assumed that load control has been applied to the holistic control case only. Compared to Scenario 2, the System LCOE is much smaller and the %delta metric is much larger which clearly shows the advantages of demand management. Also, this scenario meets the second SHINES criterion as %delta metric is greater than 20%. The load control algorithm is especially effective in reducing the Transmission and Ancillary Service cost through PLR. Figure 2-24 shows the total system load with and without the load control algorithm during 4CP windows in summer months in 2016. The controlled load is consistently smaller than the uncontrolled load. As PLR is the most valuable application, the System LCOE significantly decreases after demand management. Note that, the cost associated with demand response controls including the cost of smart thermostats is ignored. This assumption is consistent with utility Bring Your Own Device (BYOD) programs.



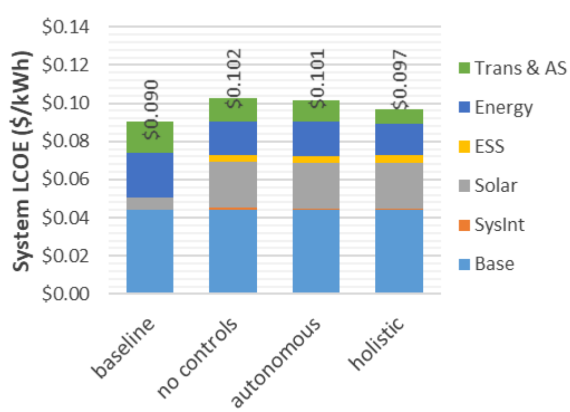


Figure 2-23 Scenario 14, Left: System LCOE results for each control strategy, Right: System LCOE breakdown

Table 2-13: Scenario 14; System LCOE results summary

Scenario	Baseline	No Controls	Autonomous	Holistic
Solar PV penetration by energy (%)	5%	25%	25%	25%
System LCOE to Serve Load ($/kWh)				
low DER costs, low ERCOT prices	$0.084	$0.093	$0.09	$0.088
low DER costs, high ERCOT prices	$0.096	$0.102	$0.10	$0.096
mod. DER costs, mod. ERCOT prices (charted in, Figure 2-20 left)	$0.090	$0.102	$0.101	$0.097
high DER costs, low ERCOT prices	$0.084	$0.105	$0.104	$0.100
high DER costs, high ERCOT prices	$0.096	$0.114	$0.112	$0.108
System LCOE to Serve Load by Category (mod. case charted in Figure 2-20 right)				
Base distribution system infrastructure	$0.044	$0.044	$0.044	$0.044
System integration	$-	$0.001	$0.000	$0.000
Solar CapEx and OpEx	$0.006	$0.024	$0.024	$0.024
ESS CapEx and OpEx	$-	$0.004	$0.004	$0.004
Load Control CapEx and OpEx	$-	$-	$-	$-
Net wholesale energy	$0.023	$0.018	$0.018	$0.017
Transmission and ancillary services	$0.016	$0.012	$0.011	$0.007

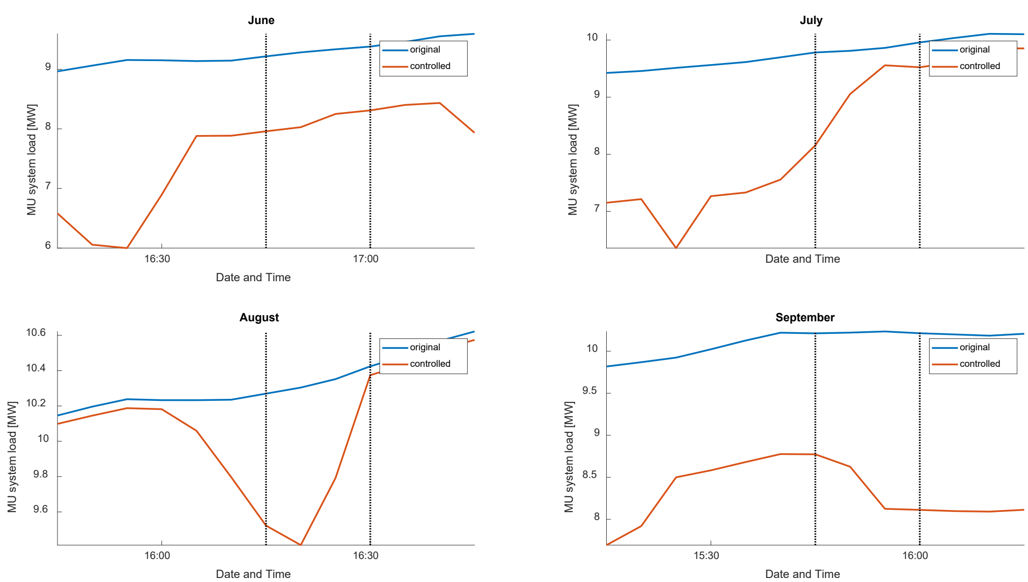


Figure 2-24 MU system load, w/ and w/o applying load control

2.4 Conclusions and Next Steps

This Final Deliverable report carried out an economic optimization analysis on select scenarios with different mixture of solar and energy storage assets. The analysis showed that:

- Utility-scale energy storage is the most economical technology among the examined technologies, assuming the power rating of the ESS is below 1 MW allowing PLR participation, shown in Figure 2-10.
- System LCOE increases as the amount of storage increases in the system. However, the rate of increase is different among the technologies. Utility-scale and commercial storage have smaller rates of increase compared to residential, again shown in Figure 2-10.
- Holistic controls have the smallest System LCOE among the three control strategies in all the scenarios.
- For residential and commercial storage and any mixtures of storage containing these two technologies (Scenarios 5-8), no controls have better performance than autonomous controls.
- %delta metric increases as the amount of storage increases in the system. For residential and commercial storage, the increase is very small. The utility-scale storage has the sharpest slope suggesting that holistic control is more valuable when combined with utility-scale storage, shown in Figure 2-11.
- Distributed solar is more economical compared to community solar, if the size of the community solar plant(s) is larger than 1MW (represented in Scenarios 2 and 12). If the plant can be broken into smaller plants each of which has a capacity smaller than 1MW then community solar will be the preferred technology.
- At the current penetration of 8,697 EVs, the impact of EVs on the system is not significant. The use of EVs for providing grid services is limited due to low availability, shown in Scenario 13.
- Load control is a very effective strategy in reducing System LCOE as it decreases the total system load which directly contributes to PLR, shown in Scenario 14.

The economic optimization presented in this report searched for a 'locally' optimized design mix for Austin SHINES. Analysis of more scenarios can increase the confidence and accuracy of the proposed design mix, especially scenarios that examine changes in the system conditions such as load and solar penetration, as well as changes in the energy market rules. The following scenarios can be included in the next steps of the economic optimization:

- Scenarios with higher penetration of solar (30%, 35% and 40%). These scenarios can help to identify the impact of reliability-related constraints (voltage raise and fluctuations, and congestion) on System LCOE.
- Scenarios with higher penetration of solar and "CAISO-like prices". These scenarios can help study the System LCOE under the duck curve conditions.
- Scenarios with higher penetration of EVs which consider public and fast DC chargers. These scenarios are especially important mainly because public chargers and fast DC chargers have larger power ratings compared to residential chargers and their impact on system load is more significant.

Section 3 **Summary of Applied System LCOE Modeling**

3.1 Optimized Mix

Based on the conclusions of the economic optimization, utility-scale storage is the most economical option among the three available technologies. Also, load control is a very economical asset for reducing System LCOE through peak shaving.

Table 3-1 repeats the information in Table 2-1 but with an extra column containing the holistic System LCOEs from the economic optimization. The smallest System LCOE, as expected, belongs to Scenario 14, which deploys 2MWh of utility-scale storage and a load control mechanism. This scenario is the most economic among all the scenarios. If the Austin Energy system is expected to grow in the near future, the second most viable option would be a system with more utility-scale storage (depending on the expected load, and solar penetration growth) and a load control mechanism in place. The second smallest System LCOE belongs to Scenario 13, which deploys 2MWh of EV capacity. System LCOE of this scenario is small, mainly because the storage capacity came at no cost. However, due to very low availability, the aggregate EV storage capacity is very small, which limits the availability of grid services. To rephrase, Scenarios 2, 6, & 8, nearly guarantee the storage will be available (assuming it has the right SOC), but with the EVs, the availability is not guaranteed. Needing a certain amount of storage to enable increased penetration in solar, 2MWh of EV capacity is not equivalent to 2MWh of stationary storage capacity, due to its transient nature and other uses. Therefore, Scenario 13 may be viable in the system with 25% penetration of solar, but this Scenario cannot accommodate any additional solar capacity, in near future.

Table 3-1: Summary of System LCOE results

Scenario	Solar penetration by energy (%)	Distributed solar (MW)	Community solar (MW)	Utility ESS (MWh)	Residential ESS (MWh)	Community ESS (MWh)	EV (MWh)	Load Control	System LCOE* ($/kWh)	%delta Metric
1	25	4.9	0	1	0	0	0	No	$0.100	8%
2	25	4.9	0	2	0	0	0	No	$0.101	10%
3	25	4.9	0	4	0	0	0	No	$0.103	14%
4	25	4.9	0	6	0	0	0	No	$0.106	17%
5	25	4.9	0	0	1	0	0	No	$0.101	5%
6	25	4.9	0	0	2	0	0	No	$0.103	5%
7	25	4.9	0	0	0	1	0	No	$0.100	5%
8	25	4.9	0	0	0	2	0	No	$0.101	5%
9	25	4.9	0	2	1	1	0	No	$0.105	9%
10	25	4.9	0	1	2	1	0	No	$0.106	6%
11	25	4.9	0	1	1	2	0	No	$0.105	7%
12	25	1.8	0	2	0	3.1	0	No	$0.102	10%
13	25	4.9	0	0	0	0	2	No	$0.099	6%
14	25	4.9	0	2	0	0	0	Yes	$0.097	46%

*Represents the “mod. DER costs, mod. ERCOT prices” of Holistic controls

3.2 Methodology to Modeling Conclusions

Within the Austin SHINES project, the idealized solution has been framed as a pathway towards optimizing design of both DER asset mix and control values of these assets, on the distribution grid. The context for this optimization derived from the Economic Modeling and Market Simulations Working Group (EMMS WG). Their development of System LCOE to Serve Load metric is discussed in Final Deliverable 1 (FD-1); specifically, Section 7 Summary of Key Findings addresses the merit, limitations, and computational quality of asset and control valuation. Just as any equation can yield percent error, this should be adequately considered before interpreting the scenario results of this report. And as many changes have occurred through the years of this project, including capital costs or simply the cost associated with naiveté and setting precedents, these fluctuations also carry some influence. From input to output of the methodology, however, the proportional relations brought out by these scenarios does provide important illuminations and answers to the optimal design solution.

Modeling has demonstrated the differential value of DER integration, should be further investigated and refined. Both modeling and field demonstrations indicate costs for DER deployments and integration are higher than the potential value they can generate at this time. Understanding the sensitivity of models is critical to predictive analytics and ability to forecast tipping points for the economic viability of future deployment and integration. To realize a positive differential value of DER from a control perspective, some combination of the following would need to occur.

- Additional market opportunities paired with more responsive controls and inverters, would need to become available in the ERCOT market
    - Market prices would need to rise and/or become more volatile
- Reliability issues would need to start occurring on Austin Energy’s system, likely due to higher (>25% load served by PV) renewable penetration, and the value of reliability would need to be quantified
- The costs of communicating with smaller DER assets beyond the grid’s edge would need to reduce, potentially from using monthly cellular subscriptions to leveraging the network in place for Advanced Metering Infrastructure (AMI)
- Additional DER types with differing value propositions, such as electric vehicles and load control, would need to be integrated into the control platform at larger scales to realize the benefits of value stacking through asset diversity, as recognized in Scenario 13

In seeking to prosper DER penetration and make sensible its application, scenario results show Austin Energy would be better suited to engage in further modeling versus fielded demonstration. Utilizing assets deployed during the project, continued activities will include continued performance analysis of the ESS's, streamlining control system architecture, developing integrations for additional DER types, and adopting tools to monitor grid opportunities for DERs. From the utility perspective, to cooperatively develop a modeling tool and deploy three scales of assets required one concerted leap of faith. The work of engineers, analysts, developers, and many other experts challenged their capabilities against emerging technology. With the project results, those involved, and the report audience may translate this leap into strategic footsteps and roadmaps.